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US 4958686 A

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INT CL[5] E21B
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(71) Applicant
BP Exploration Operating Company Limited

(Incorporated in the United Kingdom)

D'arcy House, 146 Queen Victoria Street, London, EC4V 4BY, United Kingdom

(72) Inventor
Hans Paul Hopper

(74) Agent and/or Address for Service
M MacLeod
BP International Limited, Patents & Agreements Division, Chertsey Road, Sunbury-on-Thames, Middlesex, TW16 7LN, United Kingdom

(54) Multiple concentric bore tubing hanger

(57) A multiple concentric bore tubing hanger suitable for an oil or gas well having two or more annuli has an outer portion 10 sealing one annulus, and at least one inner portion 13 sealing at least one other annulus. At least one portion, and preferably all the portions, has a passage leading to the sealed annulus with an associated annulus shut off mechanism 18, 30, which may be across the passage. The outer 10 and inner 13 portions are separate but when placed together form a unitary tubing hanger sealing two or more annuli. The use of the multiple concentric bore tubing hanger simplifies the completion of the well and allows two or more annuli to be used for production or control of the well.

Fig.8

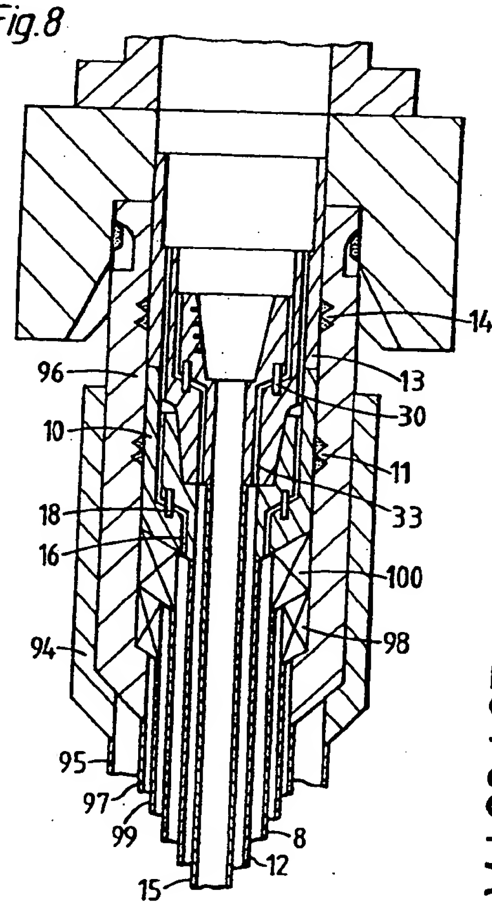

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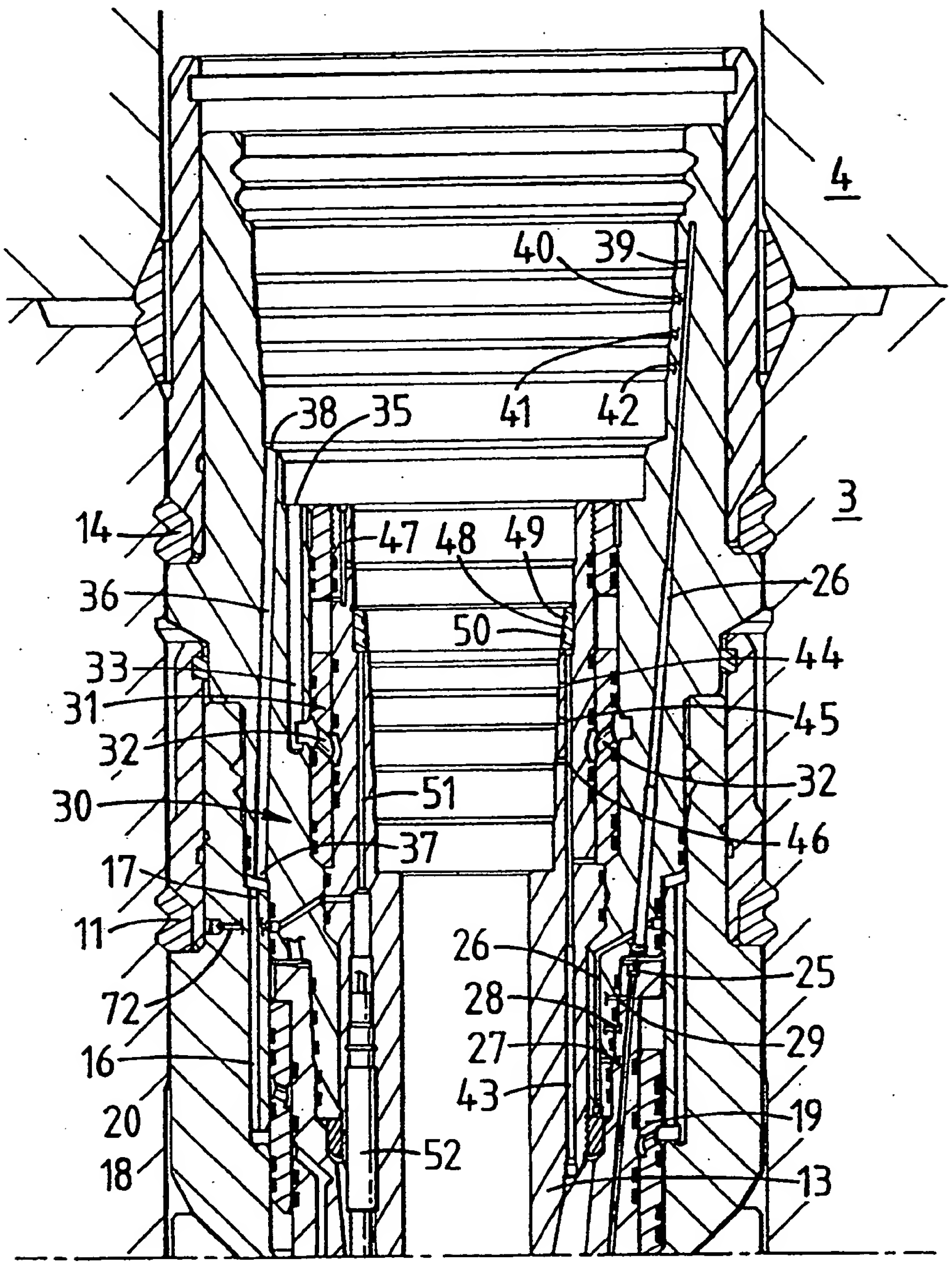
Fig. 1A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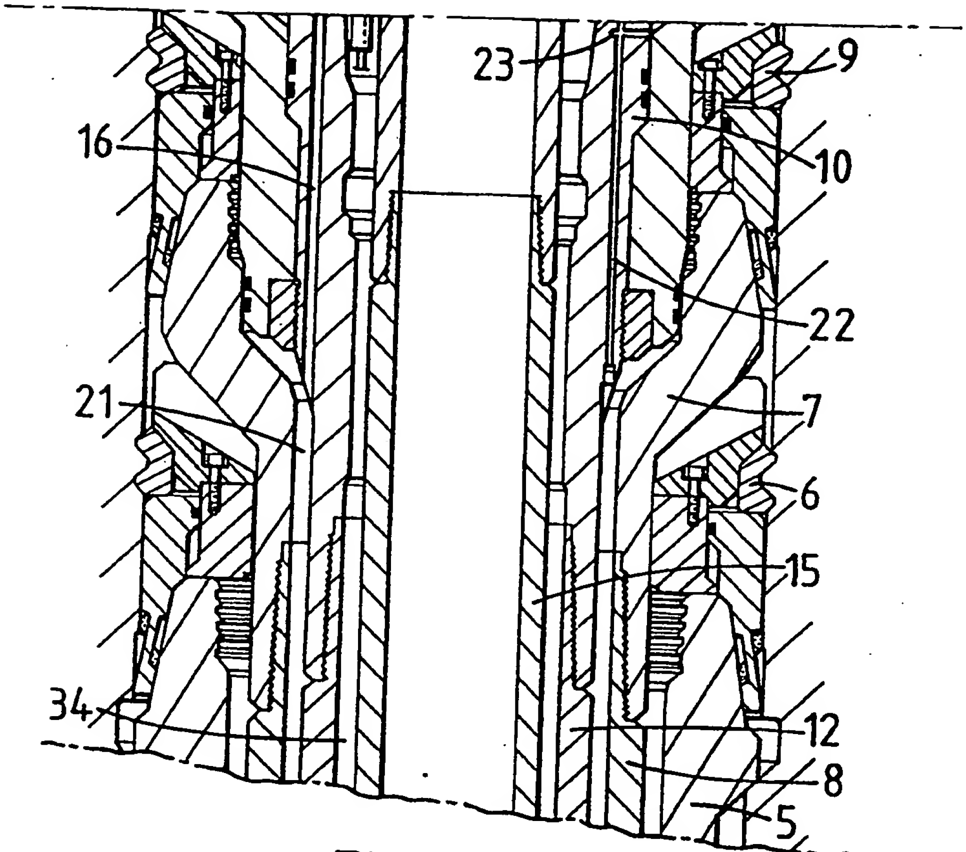

Fig.1B

Fig. 2

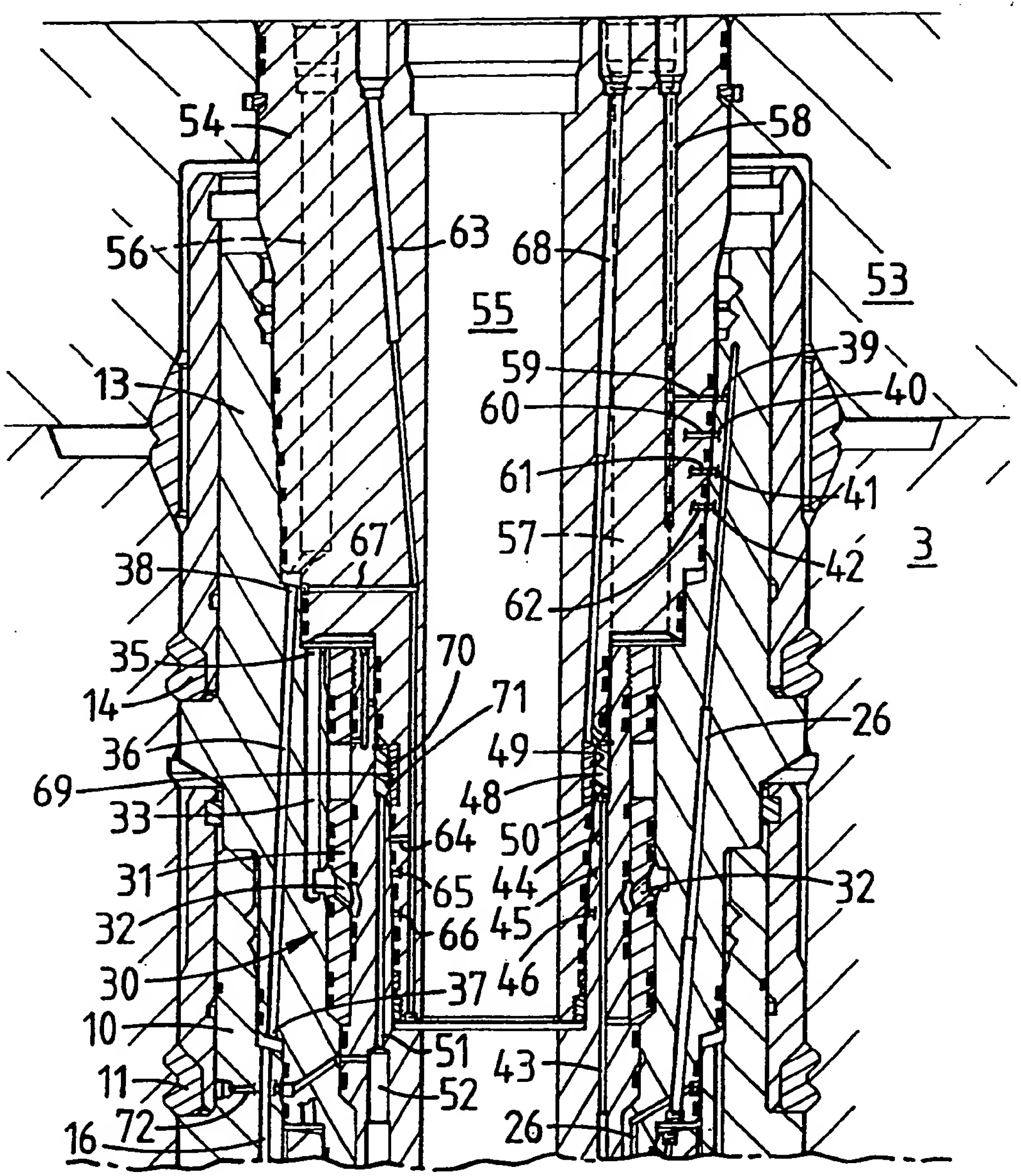
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Fig.3

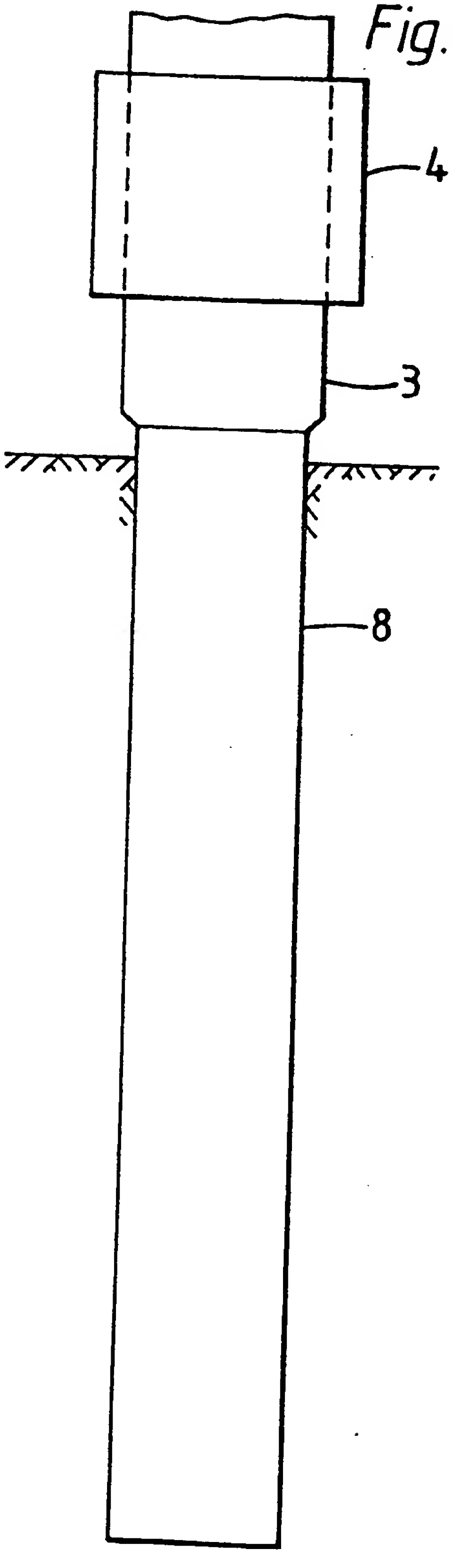
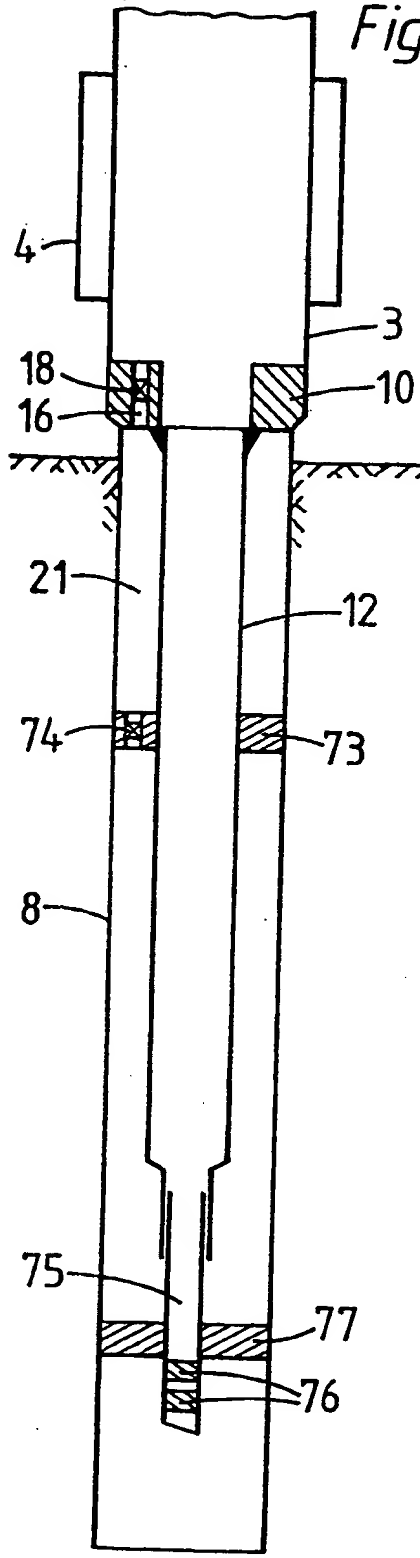


Fig.4



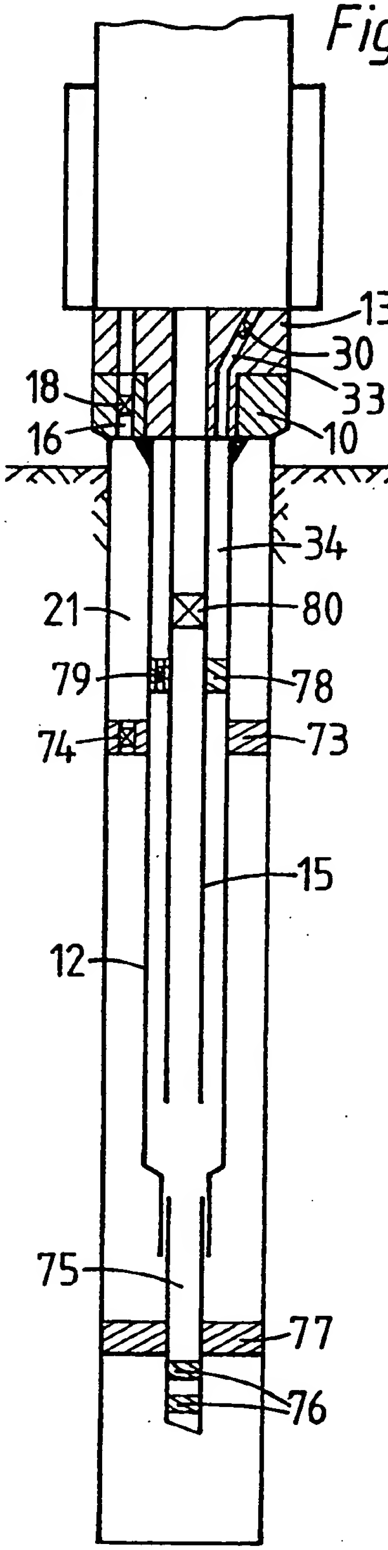


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Fig.5

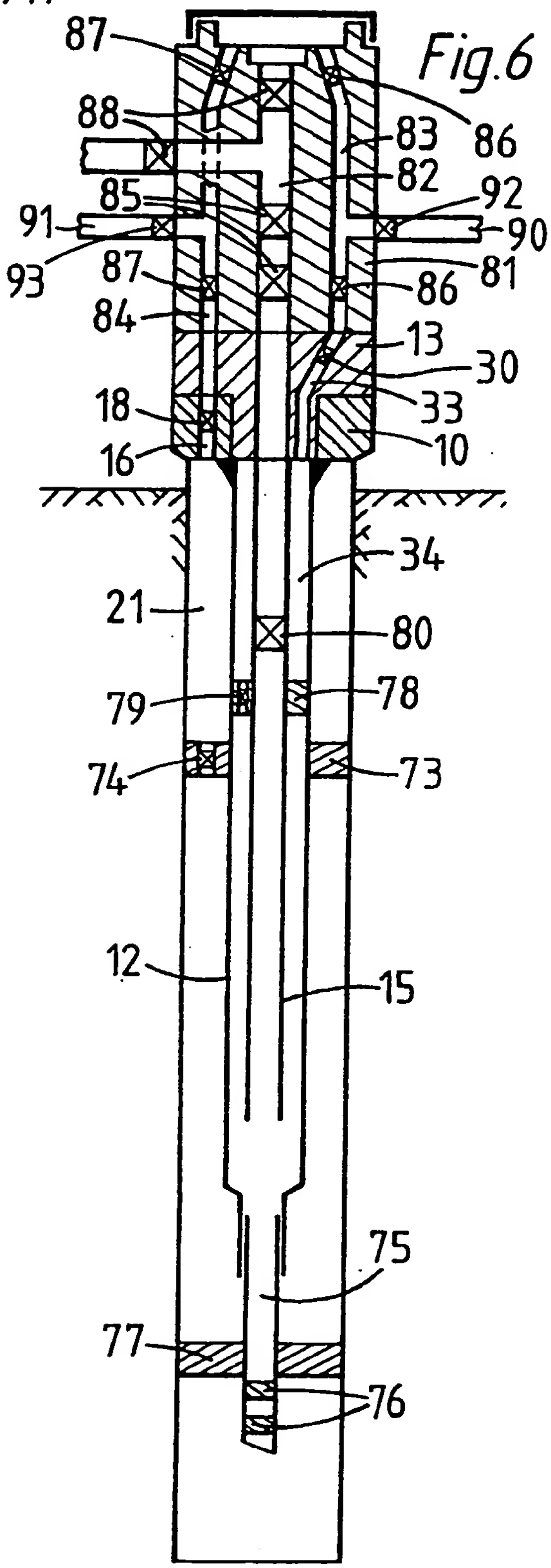

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Fig.6

Fig. 7

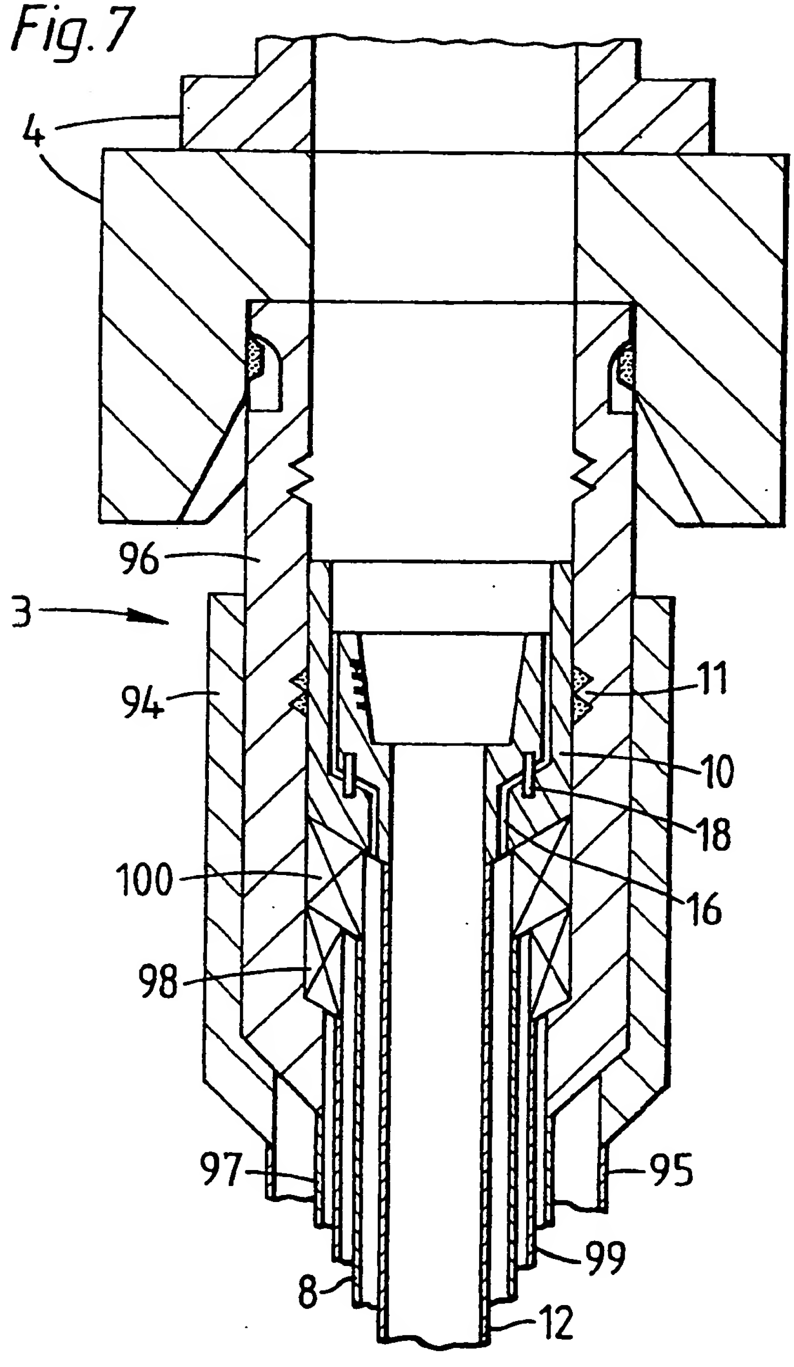

Fig.8

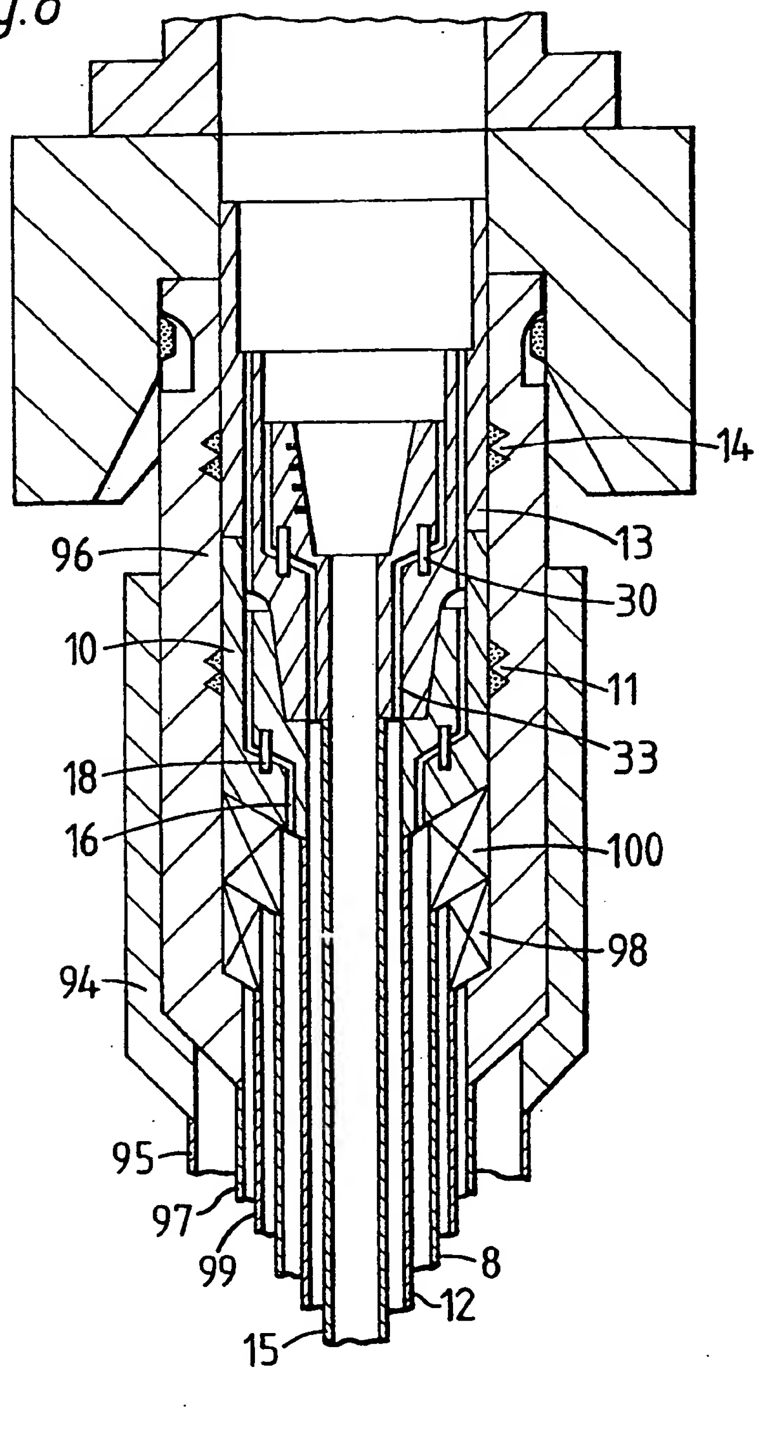

Fig. 9

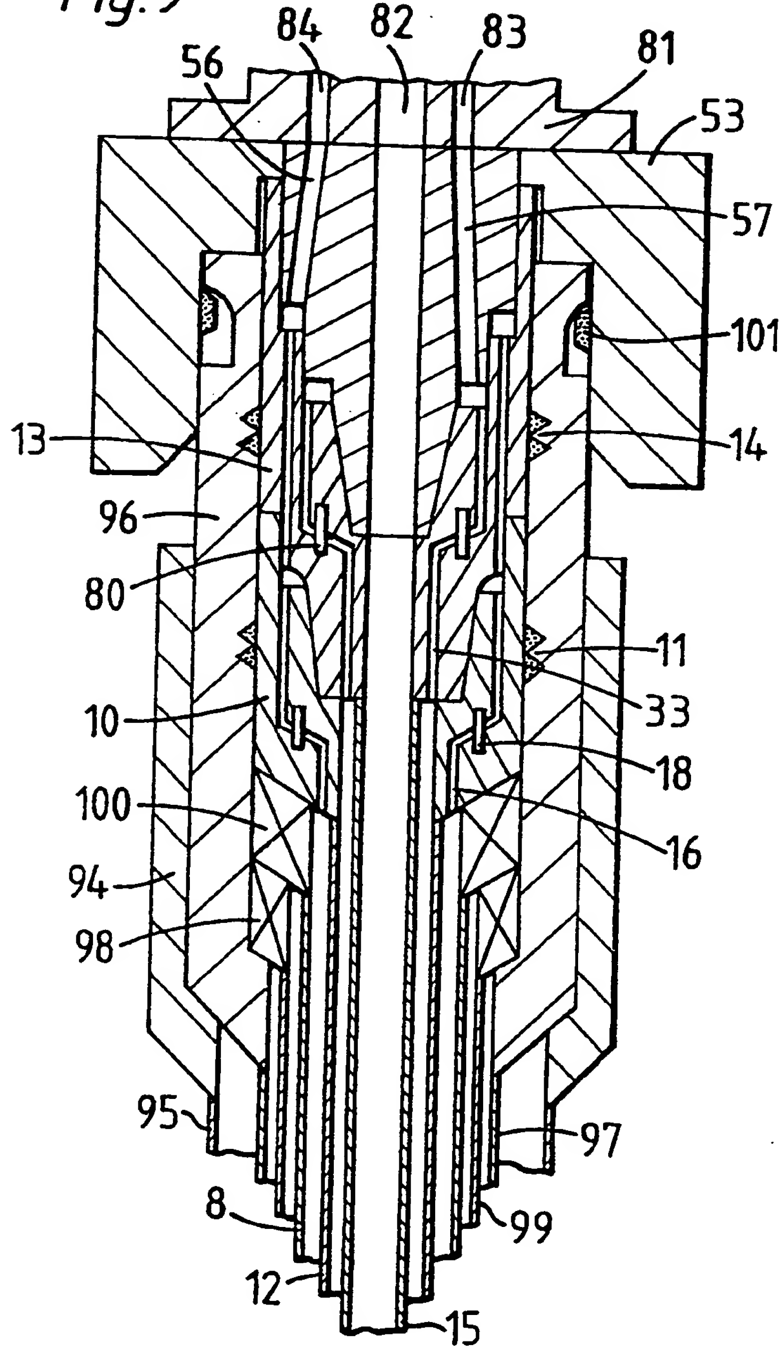
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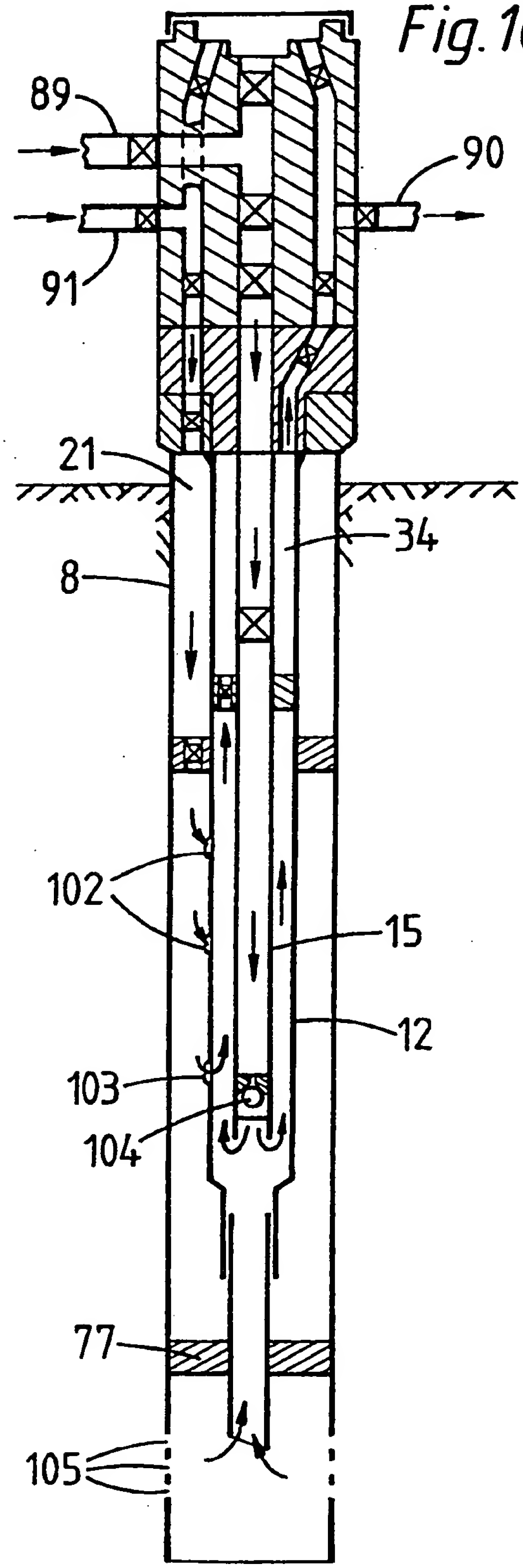
Fig. 10



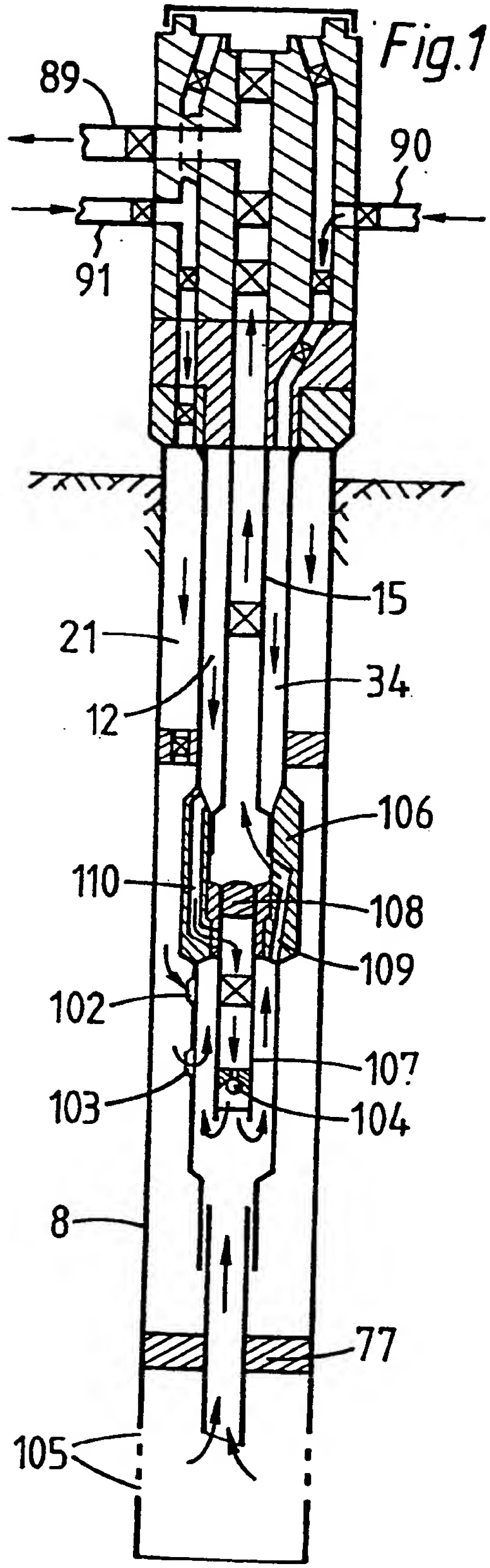

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Fig.11

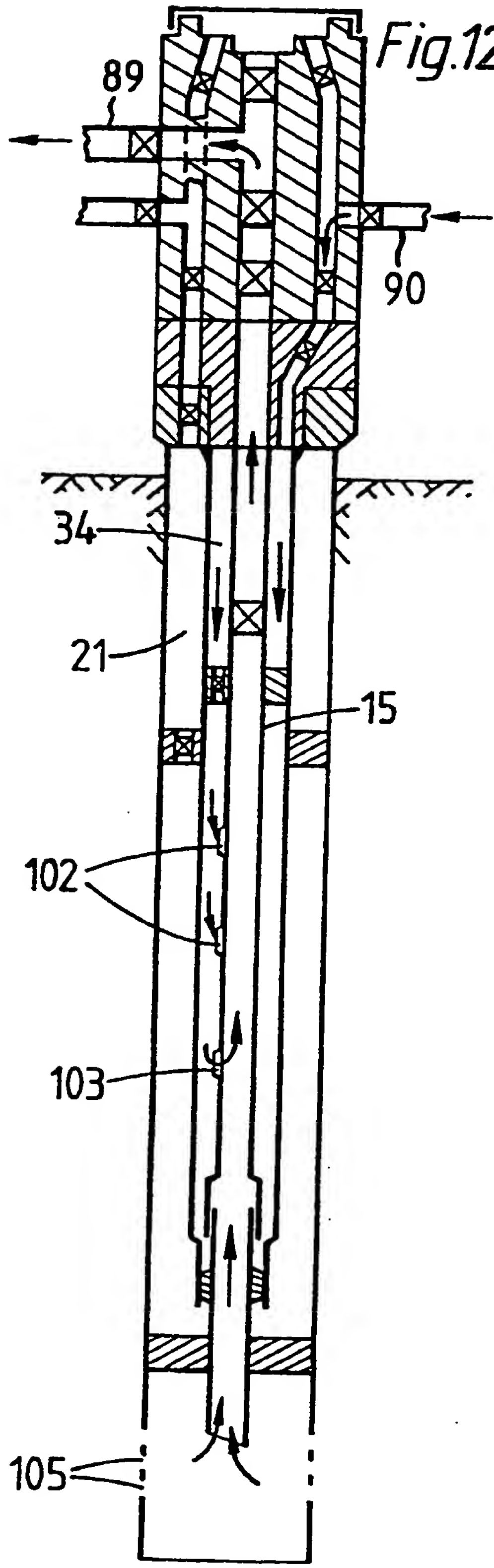
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Fig.12

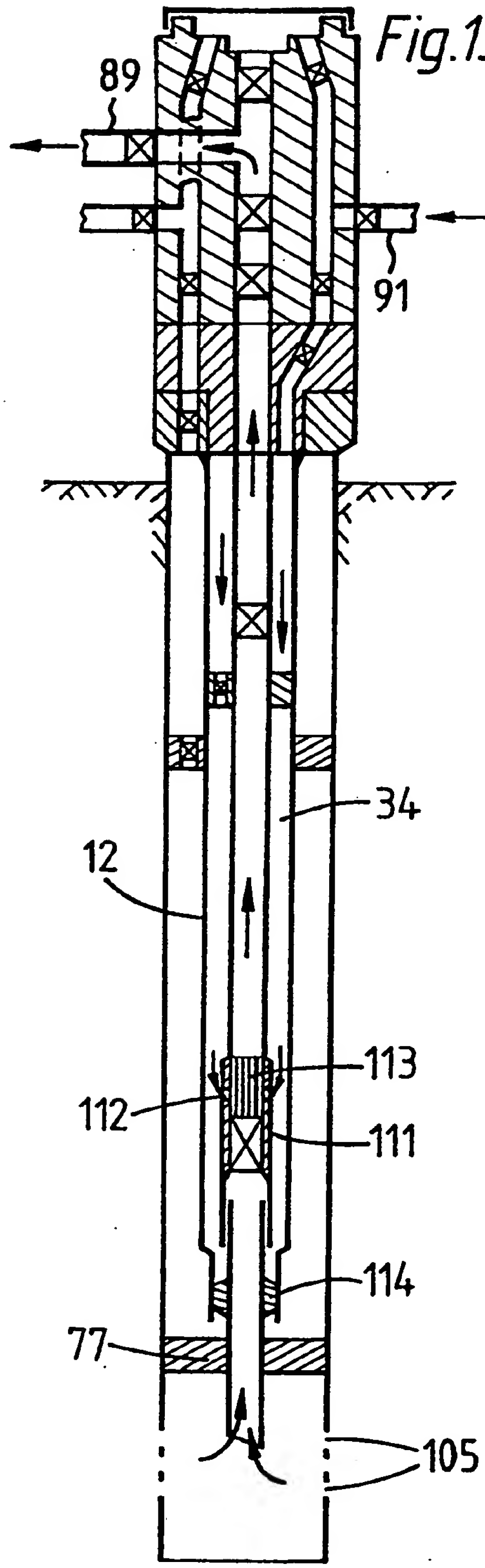

Fig.13

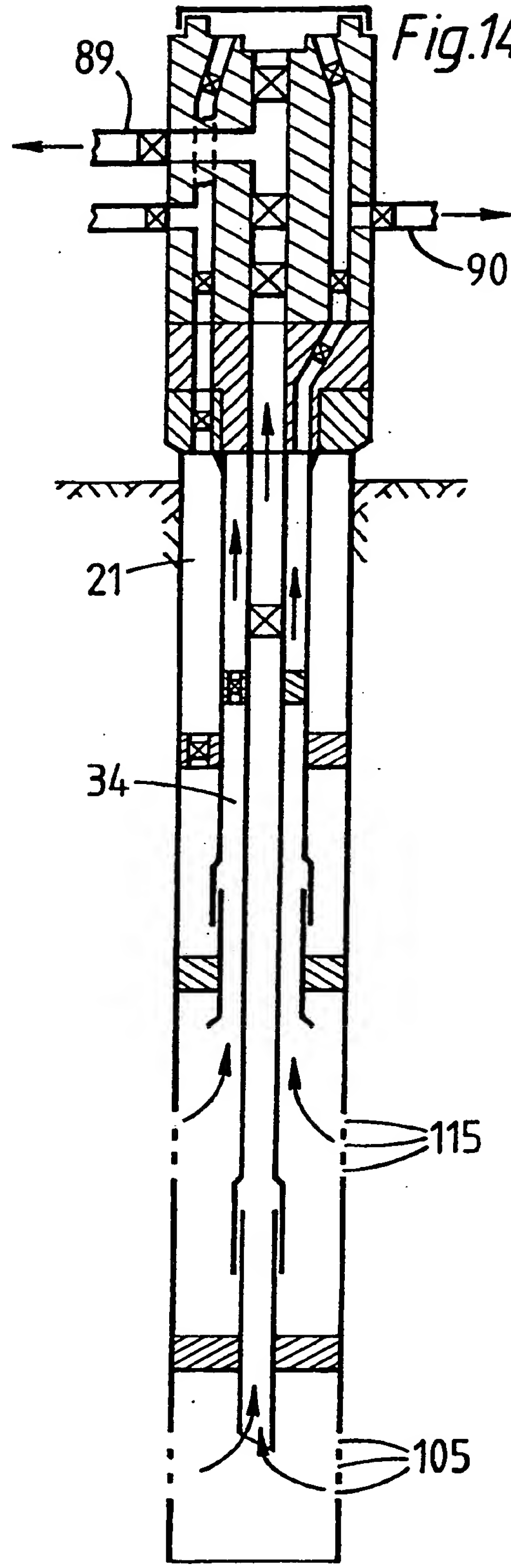

Fig.14

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MULTIPLE CONCENTRIC BORE TUBING HANGER

This invention relates to a multiple concentric bore tubing hanger for an oil or gas well capable of sealing two or more annuli of the well and preferably having two or more shut off mechanisms for these annuli.

The specification of UK Patent Application No 2214543-A describes and claims an annulus shut-off mechanism with fail-as-is logic suitable for use in the annulus of a concentric bore tubing hanger of an oil well comprising:

an enclosure across the annulus having inlet and exit ports,

a sleeve, capable of sliding in the enclosure, having an aperture capable of aligning with the inlet and exit ports,

primary means for sliding the sleeve to the open or closed position, and

secondary means independent of the primary means, for sliding the sleeve in the event of failure of the primary means.

The specification sets out the advantages of concentric bore tubing hangers for oil and/or gas wells, particularly sub-sea wells, as compared with dual bore tubing hangers as follows:

1. The need for precise orientation of the hanger is eliminated.

2. Larger tubing bores can be accommodated, without loss of annular area.

3. No annulus wireline work is required so that no vertical access to the annulus is necessary.

4. Concentric non-orientating conductive couplers can be used

to transmit electrical power to down hole instruments and monitors, with sufficient concentric space for the conductive couplers to be large enough to transmit power to electrical equipment and instrumentation gauges.

5. The requirement for short annulus strings is eliminated.

Although UK Application No 2214543-A is not limited to a unitary concentric tubing hanger with a single annulus shut-off mechanism, only such a unitary hanger is specifically described. However, oil and/or gas wells may have two or more annuli which are used, directly or indirectly, for oil or gas production.

An example of an oil or gas well having two annuli and a central bore is shown in UK Patent Application No 2235938-A with particular reference to Figure 5.

In any well with two or more annuli and a central bore, the advantages of using concentric bore tubing hangers increases. However, if existing concentric tubing hanger technology is used, separate tubing hangers stacked above each other will be required for each annulus, which will have to be separately placed and in the event of a malfunction, separately withdrawn. Placing or withdrawing a tubing hanger involves a number of operations including withdrawing the protective BOP, running an intermediate connector with an upper hanger profile, and then replacing the BOP, such a sequence being required for each tubing hanger placed or withdrawn.

The present invention reduces the number of operations required in placing or withdrawing concentric bore tubing hangers.

According to the present invention a multiple concentric bore tubing hanger suitable for an oil or gas well having two or more annuli comprises:

an outer portion sealing one annulus,

at least one inner portion sealing at least one other annulus the innermost portion having a central bore,

at least one of the outer or inner portions having a passage leading to its annulus with an associated annulus shut off mechanism,

the inner portion or portions being separate from the outer portion but capable of being placed within it so that the portions together form a unitary hanger sealing two or more annuli of the well.

In the event that a well has three or more usable annuli then additional portions can be added, each fitting within each other, and each preferably having its own separate passage and annulus shut-off mechanism leading to a different annulus of the well. However, at the current state of technology a single concentric bore tubing hanger controlling two annuli is the preferred embodiment.

While the multi-portion tubing hanger of the present invention finds its greatest utility if all the portions have passages with annulus shut off mechanisms, the tubing hanger may still be of use if not all of the portions have such passages and shut off mechanisms. As previously indicated, the multi-portion tubing hanger can be placed or withdrawn with fewer operations than separate individual tubing hangers, and a portion with no passage and shut-off mechanism would still be useful for other control functions of a well, eg it could provide an electrical pathway for down hole gauges or instruments.

The passage or passages in the tubing hanger have an associated annulus shut off mechanism or mechanisms. The term "associated annulus shut off mechanism" means that each passage is directly or indirectly controlled by a mechanism so that the flow of fluid into or out of an annulus through the tubing hanger can, for obvious safety reasons, be effectively regulated. It can be any known type of valve with fail safe closed, fail-as-is, or fail safe open logic positioned at a suitable location between the annulus and the well tree. It may conveniently be across the passage.

Thus the annulus shut-off mechanism in the portion or portions may be a slide valve with fail-as-is logic similar to that described in UK Patent Application No 2214543-A. Thus it may have an enclosure across the passage, with inlet and exit ports, a sleeve, capable of sliding in the enclosure, having an aperture capable of aligning with the inlet and exit ports, and means for sliding the

sleeve to the open or closed position. The means may be hydraulic fluid pressure applied to either end of the sleeve to move it to its open or closed position.

There may be, as in UK Patent Application No 2214543-A, secondary means, independent of the other means, for sliding the sleeve in the event of failure of the other means, but such secondary back-up means is not essential. Since in oil well practice, most failures are on the power supply side rather than in malfunctions of the equipment, the hydraulic power supply to the valves may be duplicated as a safety precaution. The overall safety of the system can be assured by correct operator procedures and equipment configurations, eg independent secondary hydraulic intervention, and down hole safety valves, backed up, if required, by the use of kill fluid.

If fail-as-is logic is not considered appropriate for the annulus shut off mechanism and/or if secondary back-up means are not convenient to instal, the annulus shut-off mechanism can have fail safe closed (or fail safe open) logic by using a spring or other automatic mechanical means to move the sleeve to its closed (or open) position in the event of hydraulic or other failure.

The outer and inner portions, being separate, can be run and landed separately and withdrawn separately in the reverse order. Both portions are of such a size that they will pass through a BOP stack. This reduces the number of operations necessary for sealing two annuli of a well, which as previously explained, has hitherto required the placing of two totally independent tubing hangers.

The outer portion may be internally tapered with the inner portion correspondingly externally tapered, so that the inner portion fits within the outer portion, with the annulus shut-off mechanisms of each portion at different levels. The inner portion may itself be hollow and internally tapered to receive a correspondingly externally tapered production stinger. The passages from both the outer and inner portions of the two-part tubing hanger feed into this stinger as does the central production bore.

This tapered form of the portions of the tubing hanger and the

central production stinger provides space for passages and for junctions across the portions leading to the normal hydraulically operated down hole safety valves in both annuli. Electrical conduits and junctions may also be provided for the supply of electrical power to instruments in both annuli, and/or to the down hole safety valves, if they are electrically rather than hydraulically operated.

The invention is illustrated with reference to the accompanying drawings in which

Figure 1 is a section through a double concentric bore tubing hanger in two parts 1A and 1B which adjoin at the horizontal dashed line.

Figure 2 is a section through the top half of the tubing hanger of Figure 1 with a production connector stinger in place.

Figures 3 to 6 illustrate diagrammatically the overall sequence of operations for the running and landing of a double concentric bore tubing hanger.

Figures 7 to 9 illustrate diagrammatically the sequence of operations in the well head for the running and landing of a double concentric bore tubing hanger, and

Figures 10 to 14 illustrate different production operations possible using a double concentric bore tubing hanger.

Figure 1 illustrates a double concentric bore tubing hanger in position at a point in time in the completion of a well after its installation in the well head and prior to the removal of the drilling BOP. The outermost item is a sub-sea 18¾ inch well head 3 to which is secured an 18¾ inch drilling connector 4 supporting a BOP stack.

The drilling of the well will have proceded in conventional manner with outer casing strings being run as required. These outer casings are not shown in Figure 1. The Figure starts with a 10¾ inch production casing string 8 supported by a 10¾ inch casing hanger 7, which is held within the well head by a lock down profile 9.

The double concentric tubing hanger of the present invention is

positioned within and above 10¾ inch casing hanger 7 and is formed of outer portion 10 with its lockdown 11. This outer portion is, in effect, a 7 5/8 inch tubing hanger supporting 7 5/8 inch tubing 12. Within and above outer portion 10, is inner portion 13 with its lockdown 14. This inner portion is equivalent to a 4½ inch tubing hanger supporting 4½ inch tubing 15.

Describing outer portion 10 in more detail, it has passage 16 the bottom end of which is open to annulus 21 between 10¾ inch casing 8 and 7 5/8 inch tubing 12. Its top end opens onto the inner surface of outer portion 10 at 17. Across passage 16 is an annulus shut off valve indicated generally at 18. Valve 18 is formed of a sealed cylindrical chamber within which cylindrical sleeve 19 is free to slide vertically. Sleeve 19 has an angled flow port 20 through it.

There are a number of passages 16 around outer portion 10 and a number of flow ports 20 through cylindrical sleeve 19, flow ports 20 lining up with passages 16 to form a pathway for fluids from annulus 21. Any convenient number of passages and flow ports may be used, a suitable number being six.

The precise number of passages and flow ports will depend on the maximum volume of fluid that may have to flow through the system. The total cross sectional area of passages 16 and flow ports 20 should exceed that of passage 36 (described hereafter) so that they are not the limiting factor to flow, ie they do not have the highest fluid velocity, which could render them liable to erosion.

Figure 1 is illustrative, the left hand side of the drawing showing sleeve 19 in its up position with flow ports 20 not adjacent to passages 16 and hence with the valve closed. The right hand side of the drawing shows sleeve 19 in its down position with flow ports 20 in line with passages 16 and hence with the valve open. Since sleeve 19 is cylindrical, it will be appreciated that this representation is purely for purposes of illustration and that sleeve 19 moves as a single unit to open or shut all the passages simultaneously.

Movement of sleeve 19 is controlled by hydraulic fluid through hydraulic fluid conduit 23. As with annulus fluid passages 16, there may be a number of such conduits supplying hydraulic fluid to all the hydraulic fluid controlled functions down hole and within the well head.

For purposes of simplification, the separate individual lines for each function are shown in the same elevation, although these would actually be in different ones. Thus conduit 23 depicts several conduits which extend up through outer portion 10. For the purposes of the present invention there will be a conduit leading a hydraulic fluid line to the bottom of the cylindrical chamber below sleeve 19, so that hydraulic fluid through this line will act to move sleeve 19 upwards and close shutoff valve 18. This is shown at 24. There will be another conduit (not shown) leading a hydraulic fluid line to the top of the cylindrical chamber above sleeve 19 so that hydraulic fluid pressure through this line will move sleeve 19 down to open valve 18. There will also be conduits 22 open to annulus 21 so that hydraulic lines can extend down in conventional manner to two surface controlled subsea safety valves (SCSSSV 1 and 2).

Conduits 23 are capped at their top ends 25, the lines leading into them coming through inner portion 13 of the double tubing hanger which has its own series of conduits 26. Shown in Figure 1 is branch 27 for the line leading to conduit 24 (ie for closing the annulus shut off valve) and branches 28 and 29 for lines leading to SCSSSV 1 and 2. The hydraulic fluid supply to the top of sleeve 19 for opening the annulus shut off valve can be direct from a conduit 26.

It will be appreciated that it is important to seal both the path for annulus fluids through outer portion 10 and annulus shut off valve 18 and the paths for hydraulic fluids through outer portion 10, including the interface where they cross from inner portion 13 to outer portion 10. There must also be effective sealing of outer portion 10 within 10¾ inch casing hanger 7, and between inner and outer portions 13 and 10. Seals are, therefore,

indicated in Figure 1 by solid shading at the required strategic points, without numerical identification. Most of these seals are double seals, with chemically resistant and gas decompression resistant rings.

Turning now to inner portion 13 (ie the 4½ inch tubing hanger) this has a similar general form and shape to outer portion 10. Thus it has its own annulus shut off valve indicated generally at 30, with cylindrical sleeve 31 sliding within its own cylindrical chamber and having its flow ports 32 to provide a pathway through passages (one of which is shown at 33) which extend down to annulus 34 between 7 5/8 inch tubing 12 and 4½ inch tubing 15. The bottom part of passage 33 below shut off valve 30 leading down to annulus 34 is shown by dotted lines being not in the plane of the drawing, but it will be generally similar to the bottom part of passage 16 in outer portion 10. The top part of passage 33 above valve 30 is shown leading up through inner portion 13 to an open end 35.

Another set of passages 36 open at both ends in the upper part of inner portion 13, have their lower ends 37 adjacent a void above upper ends 17 of passages 16 of outer portion 10 and their upper ends 38 on a shoulder of inner portion 13 above outlets 35 of passages 33. Near the top of inner portion 13 there are thus separate outlets for annulus fluids from annulus 21 and annulus 34.

Conduits 26 in inner portion 13, as already mentioned, provide hydraulic fluid lines across an interface between inner and outer portions 13 and 10 to control annulus shut off valve 18 and SCSSV 1 and 2 in annulus 21. Conduits 26 extends right up through inner portion 13 to its top inner surface where branches 39, 40, 41 and 42 provide inlets for the hydraulic lines to, respectively, SCSSSV 1 and SCSSSV 2 of outer annulus 21 and the closed and open sides of annulus shut off valve 18.

Another set of conduits 43 within inner portion 13 provide a similar pathway for hydraulic lines to inner annulus 34 and annulus shut off valve 30. Inlets for these lines are positioned on a lower inner face of inner portion 13, branches 44, 45 and 46 holding the lines for respectively, inner annulus SCSSSV 1, inner annulus SCSSSV

2 and the closed side of annulus shut off valve 30.

The open side of annulus shut off valve 30 is supplied through another conduit 47.

In Figure 1, both sides of the drawing show annulus shut off valve 30 in the down open position, unlike annulus valve 18 which is shown in closed and open positions on either side of the drawing. It will be appreciated that the closed position of shut off valve 30 will be exactly the same as that shown on the left hand side of the drawing for valve 18.

In addition to providing a pathway for annulus fluids from both outer annulus 21 and inner annulus 33 and providing a pathway for hydraulic lines to annulus shut off valves 18 and 30 and to SCSSSVs in both annuli, inner portion 13 can also provide an electrical pathway to down hole gauges. Thus it has a two path conductive electrical coupling 48 with two ring contacts 49 and 50 on its inner surface, with electrical conduit 51 leading down to a lower electrical penetrator 52.

Coupling 48 may be of the type that can be flushed with a through flow of dielectric fluid to ensure clean contacts, eg couplings similar to those described and claimed in UK Patent Application 2203602. Passage 72 at the top of electrical penetrator 52 may provide an outlet for such a flush, ie for spent dielectric fluid which vents into the well head gasket test void.

Figure 1 shows the double concentric tubing hanger of the present invention at the conclusion of the well drilling sequence with all tubing in place including the central 4½ inch production tubing and with the BOP stack still in place. The final stage of completion of the well will be the installation of a 18¾ inch production connector on the well head in place of the BOP stack, this production connector having its own production stinger to provide the pathways for annulus fluids, hydraulic fluids, and electrical power into or out of the double concentric tubing hanger and the inner and outer annuli it protects.

Figure 2 shows the top half of the double concentric tubing hanger of Figure 1 with the production connector and production

stinger in place. The tubing hanger is identical with that of Figure 1 with the same reference numerals for its components.

In Figure 2 $18\frac{3}{4}$ inch production connector 53 is seated on universal wellhead 3 and within it, production stinger 54. The production stinger's external profile follows that of the internal profile of inner portion 13 with seals indicated by solid shading at all strategic points and interfaces.

Production stinger 54 has a central $4\frac{1}{2}$ inch tubing bore 55 to provide an outlet for the $4\frac{1}{2}$ inch central well production tubing. It also has passages 56 for annulus fluids from the outer annulus of the well (21 of Figure 1), the open lower ends of passages 56 being just above ends 38 of passages 36 of inner portion 13. Passages 57 provides a similar pathway for annulus fluids from the inner annulus (34 of Figure 1), the stinger 54 being slightly cut away where it sits on the shoulder of inner portion 13 which has ends 35 of passages 33.

Conduits 58 provide the hydraulic lines to control the outer annulus shut off valve (18 of Figure 1) and the two SCSSSVs in the outer annulus (21 of Figure 1), branches 59, 60, 61, 62 leading to the interface of stinger 54 and inner portion 13 so that there are hydraulic fluid pathways across the interface to branches 39, 40, 41, 42 of inner portion 13. Conduits 63 provide the hydraulic lines to control the annulus shut off valve 30 of inner portion 13 and the two SCSSSVs of the inner annulus (34 of Figure 1), branches 64, 65, 66 leading to an interface opposite branches 44, 45, 56 of conduit 43 of inner portion 13. A further branch 67 leads to conduit 47 of inner portion 13.

The final item of production stinger 54 is electrical conduit 68. This leads to electrical ring coupling 69, with ring contacts 70, 71, which mates with coupling 48 and contacts 49, 40 of inner portion 13, so providing an electrical pathway to conduit 51 and lower electrical penetrator 52. Conduit 68 besides carrying electrical wires may also carry a dielectric fluid line for flushing the contacts 49, 50 and 70, 71.

As previously indicated, a well with separate and independent

tubing hangers for 7 5/8 inch and 4½ inch tubing would require a time consuming series of operations for running and installing the hangers. After running the 7 5/8 inch hanger, the BOP stack would have to be taken off, an intermediate connector and dummy well head installed and the BOP replaced before running the 4½ tubing. Then the BOP stack would have to be taken off once more, before running the production tree and stinger. Each operation prior to removing the BOP stack requires the well to be made safe with a minimum of two isolation barriers.

Figures 3 to 6 illustrate diagrammatically the simplified series of operations when using the double concentric tubing hanger of the present invention.

In Fig 3, 10¾ inch production casing 8 is shown suspended from well head 3, with drilling BOP stack 4 in place. This is the status of the well at the start of installing a double concentric tubing hanger. Figure 4 shows outer portion 10 of the tubing hanger in place with an annulus shut off valve 18 across passage 16 which leads to outer annulus 21. The outer portion 10 supports 7 5/8 inch tubing 12, to which is attached an annulus packer 73 having a concentric annulus SCSSV 74. Tubing 12 seals onto a tail pipe consisting of production sealing slip joint 75 with positions for plugs 76 and production packer 77. At the conclusion of the installation of the components of Figure 4, testing of the added components can be carried out.

Figure 5 shows the addition of inner portion 13 of the tubing hanger supporting 4½ inch tubing 15. Inner portion 13 has its passage 33 leading to inner annulus 34 with annulus shut off valve 30 across the passage. Inner annulus 34 between the 7 5/8 and 4½ inch tubings has an annulus packer 78 with a concentric SCSSV 79 and there is also a SCSSV 80 within the central bore of the 4½ inch tubing. With the added components of Figure 5 installed, further testing of these components can be carried out.

With the components of Figure 5 in place, the well itself has been completed with two annuli and a central production bore. All the components will have been installed in safety with BOP stack 4

in place, the components passing through it, and with no need to remove it at any stage.

Figure 6 shows the final step in the well completion sequence with a well tree 81 run and positioned on the well head. Well tree 81 has three bores, central bore 82 for the production bore, passage 83 leading to passage 33 in inner portion 13 and hence to inner annulus 34, and passage 84 leading through inner portion 13 to passage 16 in outer portion 10 and hence to outer annulus 21. Each bore and passage has two valves controlling it, in conventional manner, ie production upper and lower master values 85A and 85B production swab and wing values 88A and 88B, inner annulus master, swab and wing valves 86A, 86B and 86C and outer annulus master, swab and wing valves 87A, 87B and 87C. There are side arms 89, 90, 91 for the central bore and the two passages 83 and 84. Input or output will normally be through side arms 89, 90, 91 and their control valves.

Figure 7, 8 and 9 are enlarged sections through the upper parts of Figures 4, 5, 6 respectively showing in more detail the well head and tubing hanger components.

Figure 7 thus shows drilling connector and BOP stack 4 on well head 3, the well head having 30 inch housing 94 supporting 30 inch conductor casing 95, then 18¾ inch housing 96 with 20 inch casing 97, then 13 3/8 inch casing hanger 98 with 13 3/8 inch casing 99 and 10¾ inch casing hanger 100 with 10¾ inch production casing 8.

Within the well head, outer portion 10 of the tubing hanger has been run through BOP stack 4, landed within the well head, and locked by lockdown 11. Shown diagrammatically within outer portion 10 are passages 16 with annulus shut off valve 18. Outer portion 10 supports 7 5/8 inch tubing 12.

Figure 8, equivalent to Figure 5, shows inner portion 13 of the tubing hanger run through BOP stack 4, landed within outer portion 10 and held by lock down 14. Inner portion 13 supports 4½ inch tubing 15 and has its passages 33 with annulus shut off valve 30.

Figure 9, equivalent to Figure 6, shows production connector 53 supporting well tree 81, with its central bore 82 and passages 83,

84. Within connector 53 is production stinger 54 with its central bore 55 and passages 56, 57. Production connector 53 and hence well tree 81 are locked onto the well head by lock down 101.

It will be appreciated that the passages and valves leading to the outer and inner annuli can both be used for the passage of fluids in either direction, ie for injection of fluids into an annulus and/or for extraction of fluids from an annulus. As previously mentioned the multi-portion concentric tubing hanger of the present invention may be used in combination with down hole safety valves of the type described in UK Patent Application 2235938-A. In this application an inner annulus adjacent the central production tubing is shown as being used for the injection of lift gas, the gas passing into the central production tubing through gas lift mandrels. The inner annulus could be used in this way using the present tubing hanger while still leaving the outer annulus for some other function.

Examples of production systems where the ability to use two annuli would be valuable are shown in Figures 10 to 14.

In all of the Figures 10 to 14 the triple bore well tree 81 and double concentric tubing hanger are as shown in previous figures and will not be described again in detail, except to indicate which bores and passages are used for which. Arrows indicate the flow of fluids.

Figures 10 and 11 are examples where the central bore and two annuli are used for oil production out and for gas lift and inhibitor injection in.

In Fig 10, gas for gas lift enters via side arm 91 of well tree 81 and hence through to outer annulus 21. Inhibitor is fed via side arm 89 to the central bore, and oil production comes from inner annulus 34 and out through side arm 90. To allow for this, 7 5/8 inch tubing 12 has gas lift mandrels in it, two gas lift unloading valves 102 and a gas lift orifice valve 103. The end of 4½ inch tubing 15 has a wireline retrievable one way non-return flow valve 104 in it allowing inhibitor to pass into inner annulus 34, but preventing production oil entering the central bore. The flows of

oil, gas and inhibitor are indicated by arrows. The oil producing formation is indicated by perforations 105 in production casing 8, below production packer 77.

In Figure 11, gas is injected via side arm 91 into outer annulus 21, but inhibitor is injected via side arm 90 into inner annulus 34 and production oil exits through the central bore and side arm 89. However, the gas lift through mandrels 102 and 103 in tubing 12 is into the inner annulus 34, so at this point, inner annulus 34 contains production oil. A flow cross over mandrel 106 is, therefore, inserted into tubing 12 above gas lift mandrels 102, 103. A portion of lower inner tubing 107 is hung from this mandrel 106 with wireline retrievable non-return valve 104 in it. Wire line plug 108 seals the top of this lower tubing 107. Passages 109, 110 in crossover mandrel 106 allow production oil to pass from inner annulus 34 below the crossover to the central bore above the cross over and inhibitor from inner annulus 34 above the cross over to pass into the central bore below the crossover. The various flows are indicted by arrows.

Figure 12 shows a simpler arrangement providing gas lift in circumstances when inhibitor injection is not required but a protected passive outer annulus is desired. Outer annulus 21 is therefore not used. Instead the gas lift mandrels 102, 103 are on 4½ inch tubing 15, with gas injected through side arm 90 into inner annulus 34 passing into the central bore, up which production oil passes to its outlet via side arm 89.

Figure 13 shows an arrangement using a down hole pump 111 installed at the foot of the central bore to pump oil up the bore to outlet 89. Pump 111 is a hydraulically driven pump, the drive fluid for which is sent through side arm 90 down inner annulus 34. The drive fluid could be dead crude oil. Passages 112 pass the fluid from annulus 34 to the hydraulic motor 113 of the pump, the fluids then mingling with the production oil. Outer annulus 21 is protected and monitored and not used in this embodiment. Tubing seal 114 at the foot of tubing 12 prevents escape of hydraulic fluid into outer annulus 21.

Figure 14 illustrates the possibility of producing from two different horizons. Production oil from a lower horizon 105 passes up the central bore and out through side arm 89, while oil from an upper horizon 115 passes up inner annulus 34 and out through side arm 90. Outer annulus 21 is not used, but provides protection for and monitoring of the well casing.

In some of the examples of Figures 10 to 14, only one of the two available annuli is used for fluids. Nevertheless the annulus not used for fluids is still serving a function, eg protecting the well casing and with acess available to it, it can be used for monitoring.

As illustrated by Figures 3 to 9, well completion and placement of the various components is greatly simplified, irrespective of the subsequent use made of the annuli.

Monitoring of annuli not used for a fluid flow may be by down hole instruments, the tubing hanger of the present invention having, in its preferred form, connectors for electrical power transmission.

Claims

1. A concentric bore tubing hanger suitable for an oil or gas well having two or more annuli comprising:

an outer portion sealing one annulus,

at least one inner portion sealing at least one other annulus, the innermost portion having a central bore,

at least one of the outer or inner portions having a passage leading to its annulus with an associated annulus shut off mechanism.

the inner portion or portions being separate from the outer portion but capable of being placed within it so that the portions together form a unitary hanger sealing two or more annuli of the well.

2. A concentric bore tubing hanger as claimed in claim 1 wherein each of the portions has a passage with an associated annulus shut off mechanism.

3. A concentric bore tubing hanger as claimed in claim 1 or 2 wherein the annulus shut off mechanism is across the passage and is a slide valve.

4. A concentric bore tubing hanger as claimed in claim 3 wherein the annulus shut off mechanism comprises an enclosure across the passage with inlet and exit ports, a sleeve capable of sliding in the enclosure having an aperture capable of aligning with the inlet and exit ports and means for sliding the sleeve to the open or closed position.

5. A concentric bore tubing hanger as claimed in claim 4 wherein

the means for sliding the sleeve is hydraulic fluid pressure applied to either end of the sleeve.

6. A concentric bore tubing hanger as claimed in any of claims 2 to 5 wherein the passages in the outer and inner portions terminate in the innermost portion.

7. A concentric bore tubing hanger as claimed in any of claims 1 to 6 wherein the innermost portion has hydraulic fluid lines for controlling all the annulus shut off mechanisms and down hole safety valves of the well, said hydraulic fluid lines passing across the interfaces between portions to transfer hydraulic fluid from one portion to the next.

8. A concentric bore tubing hanger as claimed in any of claims 1 to 7 wherein the innermost portion has an electrical conduit and an electrical coupling on its inner surface for the transfer of electrical power or signals to or from equipment in the well.

9. A concentric bore tubing hanger as claimed in any of claims 1 to 8 in combination with a production stinger capable of fitting within the innermost portion, said production stinger having a central bore, passages for annulus fluids and/or lines for hydraulic fluids, and/or an electrical conduit, said passages, lines and conduits aligning with the corresponding passages, lines and conduits of the concentric bore tubing hanger.

10. A concentric bore tubing hanger as claimed as claim 1 substantially as described with reference to the drawings.

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Databases (see over)

(i) UK Patent Office

(ii) ONLINE DATABASE: WPI

Date of Search
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Documents considered relevant following a search in respect of claims 1 TO 10

Category (see over)	Identity of document and relevant passages	Relevant to claim(s)
X P	GB 2243383 A (DRIL-QUIP INC) - Whole document 30 October 1991	1,7,9
X	GB 2214543 A (BRITISH PETROLEUM) - See particularly figure 3A	1,7,9
X	GB 2108551 A (ARMCO INC) - See figure 1	1
X	US 4958686 A (PUTCH) - See figures 5,6,7	1

SF2(p) SJJ - c:\wp51\doc99\fil000312

Category	Identity of document and relevant passages	Relevant to claim(s)

Categories of documents

X: Document indicating lack of novelty or of inventive step.

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